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ARE THE ELECTRIC UTILITIES GOLD PLATED? A PERSPECTIVE ON ELECTRIC UTILITY RELIABILITY

A STUDY

PREPARED AT THE REQUEST OF THE

SUBCOMMITTEE ON ENERGY AND POWER

COMMITTEE ON
INTERSTATE AND FOREIGN COMMERCE
UNITED STATES
HOUSE OF REPRESENTATIVES

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LETTER OF TRANSMITTAL

CONGRESS OF THE UNITED STATES,
HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE,
Washington, D.C., April 9, 1979.

Hon. HARLEY O. STAGGERS,
Chairman, Committee on Interstate and Foreign Commerce,
U.S. House of Representatives, Washington, D.C.

DEAR MR. CHAIRMAN: Attached is a study performed by the Congressional Research Service for the Subcommittee on Energy and Power entitled: "Are the Electric Utilities Goldplated? A perspective on Electric Utility Reliability". I believe it would be useful if this study were to be published as a Committee Print.

The study, done under the supervision of Mr. Alvin Kaufman, Senior Specialist in Mineral and Regulatory Economics, reviews the problem of electric utility reliability from the engineering and economic views and notes the answers obtained by the different perspectives.

I believe that all Members of the House will find the study to be of interest.

Sincerely,

JOHN D. DINGELL,
Chairman.

Enclosure.

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SUMMARY

Reliability is the ability of a utility to meet demand at a point in time. The two basic questions that need to be asked in regard to this ability are: 1. How reliable should the system be (number of outages per time period), and 2. How do we assure that level (reserve margin as percent of peak)? The two questions are interrelated. The current concept, based on the engineering view, would take demand as a given and design a system to supply it. Generally, only generation will be considered in the calculations even though most outages are the result of transmission failures.

Most U.S. systems are built to a reliability criterion of one outage in 10 years. Translating the criterion into a reserve margin is accomplished using one of several methods such as the contingency outage reserve criteria, capacity reserve percentage, or loss of load probability (LOLP). The latter is becoming the major method for determining reserves and has also been suggested as a rate making factor.

These methods all take account of forced outage rates and maintenance schedules, but often do not account for uncertainty and interties, nor are the cost of maintaining reserves related to the benefits accruing from that redundancy. A new method recently developed by the Electric Power Research Institute (EPRI) attempts to account for costs and benefits, as well as uncertainty. The EPRI method uses a capacity expansion model tied to a probability decision tree for demand. The model deals with fixed, variable, outage, and environmental costs. At the moment, there is insufficient data available upon which to evaluate the EPRI approach, but it does attempt to account for uncertainty.

Uncertainty results from the forecasting of demand and in the scheduled completion of new plants. For example, there is a 33 percent differential in the capacity required to meet demand between a Kwh growth rate of 4.8 percent and 7.2 percent annually. Further, a 20 percent reduction in construction will result in a 7.5 percent decline in capacity, but our assumptions result in a drop in reserve margin to only 11 percent.

At present, the U.S. electrical system is overbuilt, but utility projections indicate that by 1986 there may be no overcapacity. The Edison Electric Institute (EEI) and the National Electrical Reliability Council (NERC) indicate adequate supplies for the United States as a whole, but stipulate some regional problems as a result of difficulty in siting and completing plants. Much, however, depends on the rate at which the demand for electricity increases. If demand grew at an average of 5 percent annually between 1977 and 1986, and there was a 20 percent reduction in capacity from that currently planned, we derive a forecast at variance with the conventional wisdom. Under these assumptions, no area of the country would have less than 20

percent reserve margin in 1986. If demand growth were higher there would be some regional difficulties, depending on the strength of regional interties and the reliability level selected as suitable.

The suitable reliability level, under the economic view as opposed to the engineering view, depends on the relative costs and benefits. These are difficult to assess, but several studies have been published. All indicate the 1 day in 10 year reliability criterion is too high, but none evaluate the use of reserves as a buffer against uncertainty. These studies also have other disabilities which make the results difficult to accept. As a consequence, the current reliability criterion should be accepted until such time as a more definitive methodology evolves. This criterion, however, should be implemented taking account of interties and adjusting for the reliability of transmission and distribution.

To this end, a fresh look at reliability is required in order to develop a more appropriate methodology. This should attempt to first determine the suitable reliability level in view of the outage and other costs for each system, and then the appropriate transmission, distribution and intertie levels, as well as the generating reserves required to meet that level. The present methodology tends to give too much weight to the generating side and not enough to the major outage cause—transmission.

In addition, such computations should also take account of diversity, not only among systems, but also among customer classes within a system.

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ARE THE ELECTRICAL UTILITIES GOLDPLATED? A PERSPECTIVE ON ELECTRIC UTILITY RELIABILITY*

Introduction

The Consolidated Edison (Con Ed) blackout in July 1977 impacted millions of people in New York City and Westchester County, and is, perhaps, one of the most dramatic instances of a failure in electrical system reliability. Such reliability is, to paraphrase others, a matter too important to be left to the electric utilities. As the Con Ed incident indicated, the reliability of our electrical system impinges on our way of life, our productivity, and the future size of our electric bill. This overriding importance results from the intertwining of electricity with our economy and our lifestyle. As a consequence of this importance we have developed an almost perfect electrical system based on the assumption that the lights should always go on when one works the switch. Having the lights always go on, however, carries with it a cost in terms of capital, labor and materials.

As a consequence of the importance of reliability and the possible widespread impacts of an inadequate level of reliability, it appears necessary for the Congress to have an understanding of what reliability is, how it is computed, and what constitutes an adequate level. The latter is an effort to determine whether the benefits exceed the costs at a given level of reliability.

In addition, some reliability measures are now being utilized as part of a method of deriving marginal costs for utility rate making. A measure of the propriety of such a use is important in the overall context of utility rate regulation.

In view of the importance of the subject, and in an effort to better understand the reliability question, the Honorable John D. Dingell, Chairman of the Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, U.S. House of Representatives, requested CRS to prepare the study that follows.

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*By Alvin Kaufman, Senior Specialist in Mineral and Regulatory Economics, Langdon T. Crane, Jr., Specialist in Science and Technology, Barbara M. Daly, Senior Reference Assistant, Russell J. Profozich, Analyst in Energy and Utilities, Susan J. Bodily, Research Assistant.

Reliability - Definition and Concept

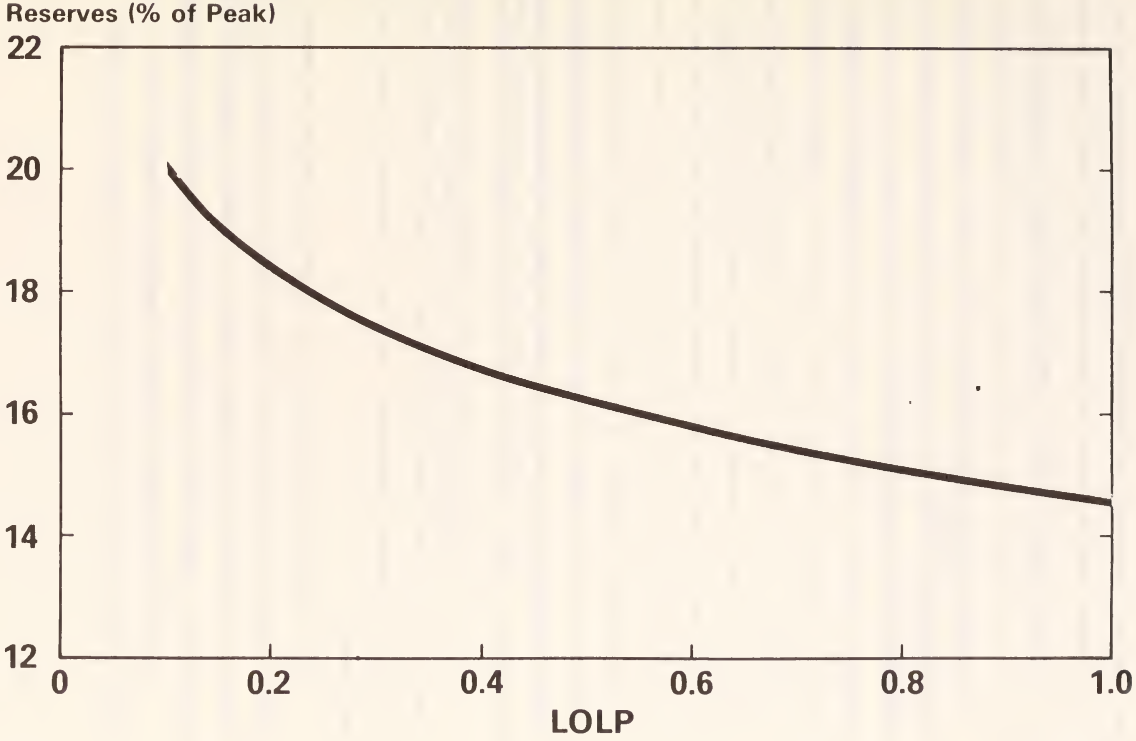
Reliabilty, for our purposes, relates to the ability of a utility to meet demand at a point in time. In looking at the subject there are two basic parts of the question. The first deals with how reliable the system should be and the second deals with what is required to achieve the prescribed goal. The level of reliability of the system is defined by the reliability criterion and the second item by the reserve margin. The latter is usually expressed as a percentage of the peak demand in Kilowatts (Kw), while the former is often stated as a number of outages over some period of time (i.e. 1 outage in 10 years). An outage is an inability to meet demand resulting in the disconnection of customers.

The reliability criterion and the reserve requirement are interrelated. As shown in figure 1, as the probability of an outage (LOLP) increases, the reserves needed to maintain that level of reliability decreases. The data used in this figure apply to a given system in a given year. While the general relationship will hold over time and regarding other systems the specific relationship will vary from year to year and system to system depending on the configuration of equipment. That is, a system highly dependent on hydro generation will have a different reserve requirement for a given LOLP than one with extensive nuclear or coal units, etc. By the same token, a system with new, large units will have a different requirement from one with small, older units. As generating units change within a system so will the reliability-reserve relationship. The reliability concept, as currently developed, is based on the assumption that all demand placed on a system must be met. Therefore, adequate capacity must be provided, not only to meet demand, but to guard against a variety of contingencies in both operations and planning. This assumption is derived from what we call the "engineering" view.

The Engineering View

Under the engineering view of reliability, demand will generally be taken as a given, and a system will be designed to meet that demand. In undertaking

Figure 1 - Relationship Between Reserves & LOLP, N.Y. Power Pool, 1975



the latter utility planning will generally involve a determination of the additions to system capacity required to meet projected peak loads. These increments will then be adjusted upward in order to guard against outages or at least to keep the probability of an outage at an acceptable level. (i.e., the reliability criteria).

The primary and generally exclusive concern in these engineering analyses is with generating capacity and its reliability. The generating component of power systems is usually considered because it is the most expensive and the most time-consuming to construct. Reliability, however,is also dependent on the proper performance of transmission and distribution facilities. For example, the Consolidated Edison Blackout of July 1977, was a failure of transmission rather than of generation. Insofar as distribution systems are concerned, some people maintain these are generally built to a lower standard than other system components so that the customer may not be benefiting from the greater reliability of the generating system. Other people maintain that higher standards of reliability are required for generating equipment in order to assure that energy is available for transmission and distribution over whatever lines do exist. It has also been maintained that the generating system should be at no greater a level of reliability than transmission and distribution.

In view of the recent Consolidated Edison blackout and the major Northeast outage of 1965, it would appear that there may be a need for additional transmission reliability as opposed to generation. This view is supported by recent data on outage causes.

Table 1 indicates that outages due to transmission failure are far more numerous, affect more people and last longer than those due to generation. It should be noted that some generating outages resulted in subsequent transmission failure and vice versa. Despite this, the outages have been classified by the primary causes.

In deriving the average transmission duration, the March 10, 1977 outage in parts of Nebraska, Kansas, Colorado and the Dakotas was excluded.

Table 1

Electric Outages by Major Cause, July 1, 1976 to June 30, 1977[1/]

	Cause	
	Generation	Transmission
Number of Outages	4	31
MW lost/outage	118	449
Customers/outage	26,210	147,832
Duration/outage (hrs)	1.7	1.9[2/]

[1/] Data Sources: FPC News Release 23206, June 13, 1977 and mimeo reports on power disturbances for the 1st and 2nd quarters, 1977.

[2/] The duration of the March 10, 1977 outage was excluded.

This outage only impacted 13,500 customers, but lasted between one and 44 days. To include this duration data would have distorted the results since such a long outage is unusual, to say the least.

The data used are based on reports filed with the Federal Power Commission (FPC, now FERC). This includes all bulk power interruptions caused by the outage of any facility operating at a voltage of 69 Kv or more and resulting in a load loss for 15 minutes or longer of at least 100 Mw for larger systems. Smaller systems report if the loss is equal to one half or more of their annual peak load.

In addition to the actual service interruptions shown in the table, there are also events requiring various load reduction measures that may not result in disconnection. We have not included these; the bulk of such incidents were also transmission related.

In any case, generating reserves are required because no machine is one hundred percent reliable. All mechanical and electrical equipment tends to be unavailable from time to time as a consequence of deratings, planned maintenance, and forced outages. The latter is the time a unit is out of service for unplanned reasons such as a breakdown. Planned maintenance, on the other hand, is time out to keep the unit operating reliably and at top efficiency. For example, the refueling of nuclear units, or the cleaning or adjusting of generating units would constitute planned maintenance. Deratings occur when equipment can no longer be operated at its rated capacity, possibly because of changes in operating conditions, or because of the advancing age of equipment. For example, a 10 or 15 year old unit may be derated because of an inability to operate at its rated capacity. On the other hand, some units may be derated after a major failure, because of a determination that the unit can not operate at its rated capacity without additional breakdowns.

Despite the availability of reserve generating capacity which minimizes the likelihood of a service interrruption, there is always a small, but measureable, probability that available generating capacity will be insufficient on a given day to supply the load demanded by customers on that day. The reliability criterion thus refers to the probability of meeting anticipated load during some time period.

The criterion that is used is a matter of judgment and is assumed, by the utilities involved,to reflect what the customer wants. Most U.S. electrical systems are designed on the assumption of one generating outage in 10 years. This criterion does not imply a full one day outage every 10 years, but rather an inability to meet load which may last for less than one minute or for several hours, once in 10 years. The actual duration of the outage is uncertain and unspecified.

In this regard we should note that the selected criterion tends to overstate the probability of an actual disconnection. Figure 2 shows that at a criterion of 60 days outage in 10 years (LOLP=6) there will be voltage reductions on 65 days per year, customer appeals for conservation on 55 days, and actual disconnections on approximately 1 day per year. At the one day in 10 criterion there would be 2 days per year of voltage reductions, 1.5 days of customer appeals, and almost no probability of disconnection. These numbers relate to the New York Power Pool, and are only cited as an example. A different set of numbers will relate to other systems since each has its own peculiarities.

The reliability criterion selected assumes that the customer is willing to pay for that level of reliability because the cost and inconvenience of a lower level would be even greater. When capacity is not adequate to meet load, the consumer will suffer a cost in terms of curtailed production, idle people and machines, damaged plant and equipment, various monetary losses

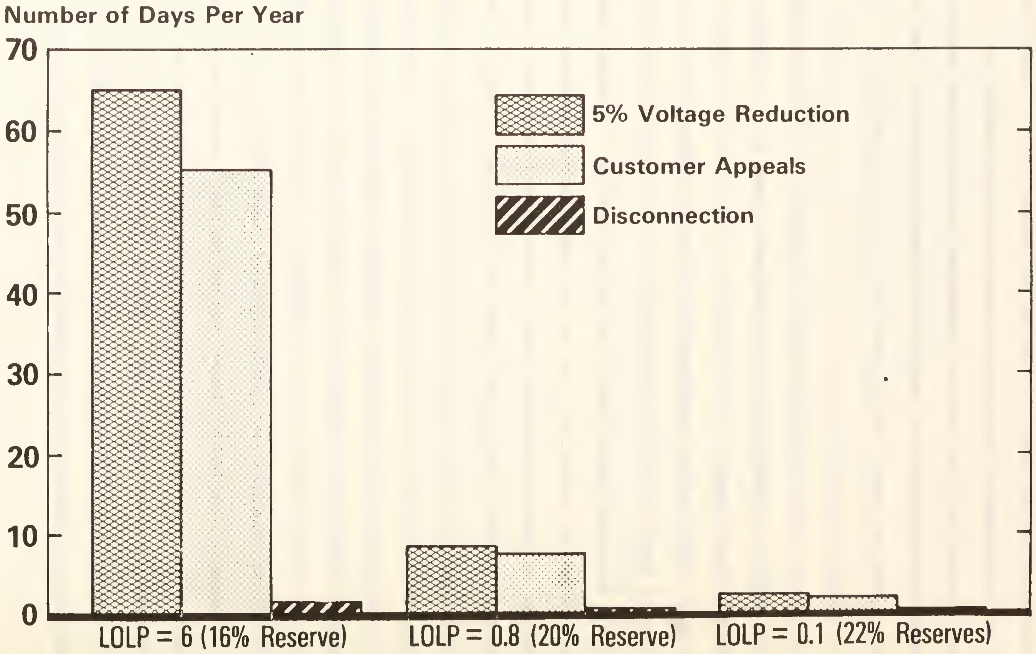


Figure 2 - The Impact of Reliability Criteria - New York Power Pool, 1976

Source: New York Power Pool 149b report, 1976, Vol. 2, p. 6

and inconvenience.[1] At the same time, however, he will want his electric rates kept as low as possible, and may not perceive a connection between his rates and the reliability criterion maintained by the utility. That is, the more perfect the system the higher the cost and vice versa.

Most of the costs incurred as a result of an outage are external to the utility. The major utility costs are lost sales and equipment damage, but the consumer and society at large may experience a large number of costs as outlined above. In some jurisdictions, these external costs have been internalized by requiring the utility to compensate customers for direct damage such as spoiled food.

Aside from the use of generating reserves to guard against contingencies on the system, reserves are often also used to guard against planning contingencies. For example, as the time required to build a plant becomes longer, the probability of correctly forecasting demand over the planning horizon becomes lower. As a consequence, an allowance may be built into the supply plan in order to assure that ample capability will be available at the time it is needed. This may also be done in order to guard against the possibility that planned units will not be on line at the time they are needed due to construction slippage and other problems. Thus, under the engineering view, once the reliability criterion has been determined as a matter of judgment, reserves are adjusted to maintain that level. The reserves thus guard against outages due to various operating contingencies as well as to problem resulting from planning uncertainties. In all cases, under this view, it is assumed that all demand must be met at all times. The reliability criterion selected is generally, for all practical purposes, a perfect system.

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[1] This subject is discussed in greater detail in Kaufman, A. and Daly, B.,"The Cost of An Urban Blackout: The Consolidated Edison Blackout, July 13-14, 1977", House Committee on Interstate and Foreign Commerce, Print 95-54, June 1978.

The Reserve Margin

The translation of the reliability criterion into reality through the establishment of reserve margins is a relatively straightforward process. These calculations are really estimates of the likelihood that the system will not be able to provide the full service demanded. Or, if one prefers, reliability calculations are estimates of the fraction of time that the full demanded service will be able to be provided by the system. The system can be of any sort, such as an electric power utility, a communications system, or even a space flight vehicle. Reliability is the calculated expectation that the system will perform to full expectations, or the likelihood of its not performing as demanded. It should be noted that this is a statistical probability, calculated on the basis of 1) past experience, 2) experiments with the same or similar components of the system, or 3) an estimate of the likelihood of various events' occurring.

The problem of providing adequate reliability in an electrical utility is complicated by the fact that this particular form of energy must be produced at the same time that it is being consumed. It is a product that cannot be stored for later delivery, nor can it be produced instantaneously in amounts that exceed the capacity of the generators which are in service at the moment. If there is an unexpected increase in demand for power which exceeds the capacity of the generators in service, then the power system operator must either add a new generating unit or, if that course of action is not possible, disconnect the generators which are operating from the load to prevent major damage from occurring to the units in service. The ability to increase generating capacity, however, is limited by the fact that all but a very few electrical generators require fairly long periods of time to start, and those that can be started fast enough to be of help in meeting unexpected emergencies are generally of limited capacity and are not capable of long-term sustained operation. Thus the power plant operator must estimate the likelihood that customers will make unusual power demands on the system, and have enough "stand-by" generators turning at the proper speed for rapid connection to the system so that all "reasonably expected" levels of power demand can be satisfied. (For the moment, we are neglecting the possibility of interties to other systems for the purchase of power.) On the other hand, it is not desirable to operate any more equipment than necessary on a stand-by basis, for there are not only fuel costs to be considered, but there are also problems of "wear and tear" on the boilers, generators, and other associated equipment. Thus, stand-by operation of a generator shortens the time span to the next scheduled maintenance repair. It may even lead to a breakdown of the generator, and thereby reduce the generating capacity of the system that is potentially available for service. Since the non-availability of one generator, either for scheduled maintenance or for the repair of a break-down, places a greater load on other (operable) generators in the system, power engineers have strong incentives other than just cost for limiting the amount of "excess spinning capacity" that is operated on a stand-by basis to meet unusual demands for power.

Since technological systems can, and do, fail, a standard approach to increasing their degree of reliability is to provide for sufficient redundancy so that total failure becomes less probable. Of course, the amount of redundancy that is needed to reach some desired level of reliability is highly dependent upon the reliability of the equipment that is available, whether one is considering the equipment already installed in the system or the new equipment to be added. Though rather little may be able to be done about the reliability of equipment that is already installed in a given power system, there may be reason to question whether the new equipment that is to be installed will be as reliable as possible, given reasonable cost-constraints. There is always the possibility, no matter what industry is being considered, that new equipment and new installations may contain few improvements over the old. Thus any evaluation of proposed increases in capacity or redundancy should seek to determine whether the engineering designs of the new equipment and installations will be effective in overcoming known and anticipated difficulties. It might even be appropriate on occasion to determine whether established standards, designs, and practices are serving to inhibit the development of cost effective solutions to existing or anticipated reliability problems. In the long run it would not appear to be economically productive to try to maintain or to improve the reliability of the electrical utilities simply by increasing generating capacity and by increasing the redundancy of transmission and distribution facilities in the absence of imaginative engineering. To be properly done, an assessment of proposed engineering designs would probably require the participation of engineers and scientists who have not become accustomed to existing practices in the industry, and who therefore may challenge approaches in design that industry experts might accept without question.

The Existing Methodology.-The degree of desirable redundancy in the system is computed using three basic approaches. These vary in sophistication from the rule-of-thumb level to the advanced, and will be discussed in order of increasing complexity below. All depend ultimately upon a knowledge of the peak load demand, and of how peak load demand varies at different times of the year and in different periods of the day, though only the most sophisticated of these methods truly incorporates this information to predict the reliability of the system. The three approaches are the Contingency Outage Reserve Criteria, the Capacity Reserve Percentage, and Loss of Load Probability.

Contingency Outage Reserve Criteria. - This approach to reliability assessment simply asks whether a power system has sufficient capacity to supply expected load demand levels in the event that one of several specific disaster scenarios should occur. The first step is to make an appropriate projection of expected peak load. This projected load is then increased by a quantity equal to the generating capacity that might not be available due to scheduled maintenance. It is then presumed that the system will be reliable if, in addition to the capacity needed to cover the projected load plus scheduled maintenance, there is sufficient excess capacity to allow for one or more contingencies of the following sort:

1. Loss of the largest generating unit in the system.
2. Loss of the two largest generating units in the system.
3. A failure in the largest transmission facility in the system.
4. A combination of the above.
5. An error of definite magnitude in load projection.

The advantages of this approach for achieving reliablility are that the method is conceptually clear, so that the adequacy of the analysis can be appreciated by non-experts. On the other hand, it provides no indication of the likelihood that the contingencies will occur, either singly or in pairs, so that the method offers no opportunity to assess whether too much reliability has been provided for. In addition, this type of approach may tempt the adoption of simplistic solutions to ensure reliability. For instance, it might appear that the best defense against the breakdown of the largest single generator in the system is to build two "largest generators" of the same type, even though a more sophisticated analysis would show that lower cost alternatives were available to achieve the same level of reliability with less excess capacity. A recent report of the Edison Electric Institute lists additional advantages and disadvantages of this method. 2/

Capacity Reserve Percentage. - The Capacity Reserve Percentage method of reliability assessment is also conceptually very simple. It consists of expressing the total capacity of the system in terms of the amount needed for expected load, plus, a "reserve" of some percentage of expected load. In other words, a system with 20 percent reserves has a total generating capacity of 120 percent of expected peak load demand. The desired reserve percentage is based on experience, presumably determined by operations primarily in the particular utility in question, and provides a rule of thumb for judging when capacity is sufficient. However, this rule of thumb has the weakness that it may not be an adequate indicator of how much capacity must be added to meet increased loads if the new generating equipment is more reliable than the old. Presumably, adjustments in the percentage would be made when this became apparent. Nor does this method of analysis lend itself to assessments of various strategies for improving reliability at minimum cost. The positive and negative attributes of the Capacity Reserve Percentage method

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2/ "Power System Reliability Assessment. Phase I- Generation Effects." A report of the Reliability Assessment Task Force to the System Planning Committee. Edison Electric Institute, 90 Park Ave., New York, N.Y. 10016 February 1977, p. 4, 6, and 16.

are outlined briefly in the Edison Electric Institute report, but perhaps it should be emphasized here that this technique is not well suited to situations in which technology is changing and may be particularly inappropriate now that interties between systems are serving to reduce the need for total self-sufficiency within any one system.

Loss of Load Probability. - The Loss of Load Probability approach is coming into wide usage, and represents a significant improvement in methodology for reliability calculations. Stated in the simplest terms, this technique calculates the probability that the system will fail to have sufficient operable generating capacity to deliver the power demanded by customers.

Loss of Load Probabilities are calculated primarily on the basis of a knowledge of two factors: 1) the peak power level (peak load) demanded by customers in each of a series of standard time intervals, such as each day of the year; and 2) the fraction of time in which each generator in the system is able to be operated -- which is the probability of having each generator operating at any particular time. It is assumed that maintenance, repairs and breakdowns of generators are either scheduled or occur randomly, so that a generator is said to have a 70 percent chance of being in operating condition at any particular time if it, in fact, has established a record of operating on 70 percent of the days of the year for the full day. On the remaining 30 percent of the days the generator would be found to have been out of service for some part of the day, though the duration of that interruption in operational capability need not occupy the full day. In other words, even momentary shutdown for a minor repair would count as a full day of inoperability.

Having compiled the individual operating histories of each generator in the system, it is then possible to determine the percentage of time in which the system will be able to generate various levels of power. For example, a small system with three generators having respective capacities of 50, 40, and 20 megawatts could generate 110 megawatts of power when all three units are operating, but with one or more of the generators out of service the system would have maximum generating capacities of 90, 70, 60, 50, 40, 20, or 0 megawatts, depending upon what generators were out of service. By knowing the actual operating histories of the generators in the system, it is possible to calculate the percentage of days in the future on which the system is likely to have maximum generating capacity at each of those levels. When these percentages are expressed as decimals, they are the probabilities that the system will have generating capacity equal to each of the levels specified above.

The next question to ask is how much of the time more power will be demanded by customers than the system can supply, given the fact that generator outages will limit the generating capacity. Stated somewhat more completely, the question is: on how many days, out of the total number of days to be considered (which would typically be 365 days, or some multiple thereof), will the projected peak power demand exceed the minimum generating capacity of the system? These calculations do not make allowance for the fact that the peak power demand might occur in mid-afternoon, while the minimum generating capacity might occur at a time of day when the full demand can be met. Further, scheduled maintenance and repairs on a generator might be delayed when other generators in the system have broken down. The ratio of the number of days on which the peak power demand can exceed the minimum generating capacity of the system to the total number of days to be considered is defined as the Loss of Load probability (LOLP).

To calculate LOLP, the historical record of the actual power demand (load) is used to find the number of days per year in which peak power demand has been between various demand levels, such as 0 and 10 megawatts (Mw), 10 and 20 Mw, 20 and 30 Mw, so forth, up to the full generating capacity of the system with all units operating. These figures are then converted into percentages of the number of days of the year, or their decimal equivalent. For example, where there is a maximum of 110 Mw of generating capacity, it might be found that the peak power demand fell in the 60 to 70 Mw range during 0.6 of the days in the year, and in the 70 to 80 Mw range during 0.25 of the days of the year, and in the 80 to 90 Mw range during 0.15 days of the year. Now suppose that the historical records show that the total generating capacity had fallen below 70 Mw during 0.001 of the days in past years, and below 80 Mw during 0.003 of the days in and below 90 Mw during 0.005 of the days in past years. We can then put these figures together to compute LOLP. Having estimated that the system will customarily not be able to supply as much as 70 Mw of power on 0.001 of the days it operates, and that a peak of 60-70 Mw can be expected on 0.6 of the days, it follows that loads of 60-70 Mw will not be able to be satisfied on 0.0006 (i.e., 0.6x 0.001 = 0.0006) of the time, or 0.219 days each year (0.006 x 365 = 0.219). Iterating this calculation for each of the other demand ranges and then adding gives us the probably generating insufficiency as a decimal.

For example:

Demand Range	Probabilities Demand		Capacity		Outage
60-70Mw	0.6	x	0.001	=	0.0006
70-80	0.25	x	0.003	=	0.00075
80-90	0.15	x	0.005	=	0.00075
					0.00210

From this highly simplified calculation we can determine that it would be reasonable to expect insufficient generation 0.21% of the time. This percentage translates into a loss of load probability of 0.77 days per year (.0021 x 365), or 7.7 days in 10 years. The computer would then relate the LOLP to the required reserve margin.

Although the example given above is considerably simplified from that made for an actual utility, it does illustrate the basic methodology. The computations, however, tend to produce results on the pessimistic side. LOLP calculations often do not take account of possible voltage reductions, interties with other systems, load control devices, interruptible contracts, etc. To the extent these factors are not considered, the LOLP will be higher than would be encountered in the real world.

Possible Shortcomings. - The three reliability assessment methods discussed above are, according to the Edison Electric Institute Report, the methods most widely used in the electrical utility industry. Each method is useful, and yet each has limitations that must be borne in mind.

In the first place, it would seem that insufficient generating capacity has not been nearly as significant a problem in power failures as transmission and distribution system breakdowns. Yet it is reported that reliability analysis is only beginning to be applied to these components of the power industry. On the other hand, the physical vulnerability of transmission and distribution systems raises questions that may be more fundamental than whether, and how, reliability techniques might be applied. The basic question is not whether these components of power systems can be improved by such measures as adding parallel capacity (redundancy), but rather whether the individual subcomponents can be made significantly more reliable through major improvements in design.

Another related set of questions arises in considering the control and operation of power systems. In the first of the two recent major power blackouts in New York, it was reported that a part of the trouble was due to operating errors that failed to contain the problem. Presumably the same is true of other power failures of lesser consequence that have occurred, and are occurring, throughout the country each year. It may be unreasonable to expect humans to make accurate assessments of the nature of problems that may be quite complex and to take the proper corrective actions in a few seconds or minutes. It could well be that this is an area where the replacement of humans by computers could produce a major reduction in the duration, and perhaps in the frequency as well, of power failures.

Since reliability analysis is necessarily limited by the degree of reliability of the available operating components, whether these are the humans who serve as operators or the switches which sometimes fail to operate properly, it would seem appropriate to examine whether improvement can be made in the operating subsystems of the power industry. It is possible with the strong focus of attention by the engineering and commercial community on such topics as aircraft design, computers, and space, that the electric utility industry has not received proper attention in terms of innovation and technical improvements. If this is the case, then it might be appropriate to promote an assessment of the state-of-the-art technology of this industry by a group of technically competent outsiders, so as to have some basis for judging the reliability of the reliability assessments made by the industry and to provide information about the possibilities for improving component and operational performance.

Apart from these considerations, which might take considerable time to examine with proper care, there are a number of other factors which would seem to merit attention in connection with estimates of power system reliability. As noted in the previous discussion of the LOLP technique, there would seem to be a number of adjustments available to operators of power systems which would reduce the probability of insufficient generating capacity to meet load demands. If these adjustments are not properly incorporated into the calculation, then the results could indicate a higher rate of failure than would actually occur. In addition, particular caution seems appropriate in using the LOLP technique to predict the reliability of systems when new equipment is to be installed. In such cases there may be no way to estimate necessary scheduled maintenance and repair times, or to estimate the frequency of breakdown of the equipment. Further, when LOLP is used to compare the effect on reliability of various strategies for expanding generating capacity -- such as installing one large generator, in contrast to adding several smaller units -- the possibilities for misestimates would seem to require particular attention, and special care should be taken to ensure that all reasonable options have been considered.

Finally, there is the matter of regional interties, which offer the possibility of considerable insurance against the effects of a local generator breakdown. Now that these are becoming extensive, the reliability of a single power system may be less significant than that of an entire region. In addition, with the growing cost of fuel, of investment capital, and of repair, some attention needs to be given to the question of how to reduce surplus generating capacity and of how to limit excess spinning capacity to the absolute minimum.

Aside from the above, the methods outlined make no effort to relate reserves to the costs and benefits. This, of course, is inherent in the engineering view. The latter assumes outage costs are greater than capacity costs.

The EPRI Methodology.[3/] - In an effort to relate reserves to the costs and benefits of reliability, as well as to take account of uncertainties, EPRI has recently introduced a new computational system that uses a capacity expansion model coupled to an electrical demand probability tree. The EPRI effort is based, to some extent, on a study by Stanford Research Institute (SRI) for the California Energy Resources Conservation and Development Commission. That study concluded: 1. that social benefits when demand

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[3/] This section is based on the following:
A. Cazalet, E.G., Bruce R. Judd, A. C. Miller III, and E. S. Rasmussen, "Decision Analysis of Cal. Electric Capacity Expansion," SRI, Feb. 1977.
B. Males, R. H., "System Reliability--How Much Is Enough?", EPRI
C. "Planning For Uncertainty", EPRI Journal, May 1978, p. 6-11.

is known will always be greater than when demand is uncertain, and that uncertainty has to be explicity treated in a model; 2. the optimal expansion rate appears to be very sensitive to the possibility of rapid demand growth; 3. Insufficient capacity appears to impose greater costs on the consumer than excess capacity; 4. the social cost of outages is an important but uncertain factor in determining the optimal expansion rate.

Proceeding from these conclusions, EPRI postulated that the planner should be looking for the optimal capacity expansion plan in the face of uncertain demand rather than planning for a specific demand. To provide an acceptable tool to determine the optimal plan, EPRI has developed a capacity expansion model intergrated with a probability decision tree for demand. The model deals with four types of cost: fixed, variable, outage, and environmental. The fixed costs are the carrying charges on capital investments. Variable costs include fuel, labor, maintenance, and parts, as well as the cost of meeting demand from interties, interruptible customers, and voltage reductions. Outage costs include the customer cost of maintaining emergency generation, spoilage, lost business as a consequence of an outage, etc. Environmental costs are those associated with electric power generation.

The decision tree has each node labeled with a probability of occurrence representing the fact that demand growth becomes increasingly uncertain as one looks further into the future. The model generates a curve associated with a demand forecast category at a given reserve margin.

In the model, as reserve margins increase, fixed costs rise and variable and outage costs decrease. Environmental costs are held constant. The result is an asymetrical U-shaped curve. The bottom of the curve locates that level of reserve margin that minimizes consumer cost (as defined by EPRI). The asymetry of the curve indicates that costs at the lower reserve levels are significantly greater than at the higher levels. If demand is consistently higher than expected, a utility with a low reserve would have to install expensive short-lead time generation, improve interties, depend on interruptible service, or incur outages. The cost of these measures is greater than the cost of supporting the higher reserve margin levels.

The study also indicated that the effect of demand uncertainty is dependent on the specific electrical system being analyzed. In some cases, as a consequence of the model calculations, reserve margins believed optimal for a system will be barely increased over what the planner has estimated. In other instances margins may rise 5 percentage points or more.

The general shape of the curves is not affected by the level of outage cost used. A high cost will increase the value of higher margins, but does not increase the optimal margin requirement substantially.

At the moment, there is limited information available upon which to base a judgement of the propriety of the model. It does, however, attempt to explicity account for uncertainty, outage cost, and other items usually considered external to the model.

The Wheel of Fortune

The methods outlined above attempt to explicitly take account of forced outages, maintenance requirements, deratings and other operating contingencies, but in the most commonly used methods the selected reserve margin tends to implicitly take account of the uncertainty in forecasting both demand and the completion of plant construction. It, therefore, would be useful to review the sensitivity of reserve margins to such estimates. In doing so, in this particular instance we are assuming the current reliability criteria to be correct. The suitability of that assumption will be discussed at length in a later section.

Demand Forecasts. - At the moment, the U.S. appears to stand at the inflection point on the demand curve. As a consequence there is great uncertainty as to the magnitude of future requirements. Electrical consumption had doubled every 10 years for a large portion of this century. In recent years, since the 1973 oil embargo, growth has been at a much reduced rate. Inasmuch as the utility industry generally perceives overcapacity as a lesser evil than undercapacity, there is a tendency to inflate future reserve margins in planning the growth of the system as a hedge against resumed growth.

To illustrate the uncertainties, CRS anticipates future electric energy growth rates (Kwh) in a 4.8-5 percent annual range between 1976-1990; NERA in the 4.8-6 percent range between 1974-85;[4/] EPRI in the 5.4-7.2 percent range between 1975-85; and Electrical World at 4.7 percent between 1976-90.[5/] while some of the

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[4/] Guth, L. A., "The Magnitude of Possible Shortages in Electricity Generating Capacity Through 1985: A National Perspective," National Economic Research Associates.

[5/] Electrical World, "28th Annual Electrical Industry Forecast," September 15, 1977, p. 43-58.

differences can be explained by the different time periods covered by the forecasts, it is obvious that there is uncertainty concerning future growth. Further, the 1977 NERC report indicates a drop of approximately one year's growth by the tenth year compared with the previous year's forecast. It indicates a 5.7 percent annual growth rate over the next decade.[6/]

The various growth rates would have a substantial impact on the required capacity. To illustrate, if we assume load factor at 60 percent, the required reserve margin at 20 percent of peak, and growth in Kwh sold at annual levels of 4.8 percent, 6 percent, and 7.2 percent, we get a range of 814 to 1118 million Kw of capacity or a spread of approximately one-third (Figure 3). Given this substantial difference, and the fact that most utility forecasts are under fire as too optimistic, it would not be beyond the realm of possibility to select what appears to be a logical growth rate but postulate a reserve margin several points higher than normally needed in order to provide a hedge against demand error.

The forecast uncertainty is further complicated by the need to select a future load factor (LF) in order to convert Kwh into peak demand.[7/] For example, if LF were as low as 58 percent or as high as 64 percent, the projected peak (including reserves) at the 6 percent annual growth level would

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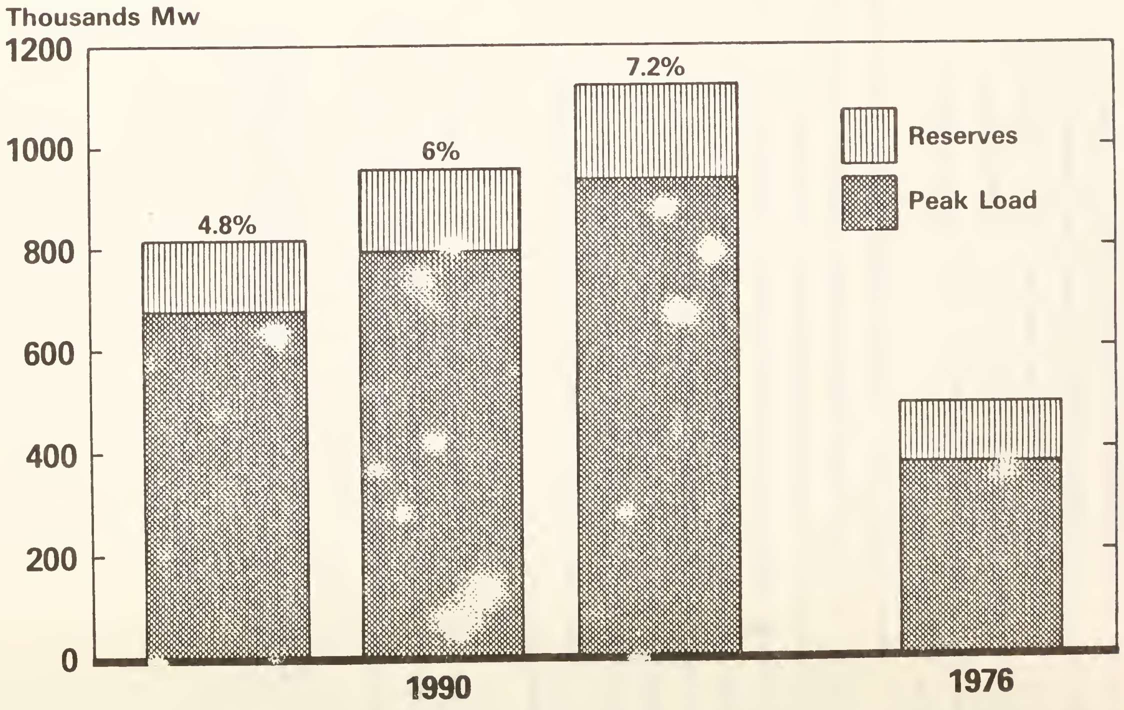
[6/] Interregional Review Subcommittee of The Technical Advisory Committee, "7th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems", National Electrical Reliability Council, July 1977, p. 3.

[7/] $LF = \frac{\text{Kwh}}{\text{Peak x 8760 hrs.}}$

Figure 3 - Required Capacity in 1990, Various Annual Consumption Growth Rates

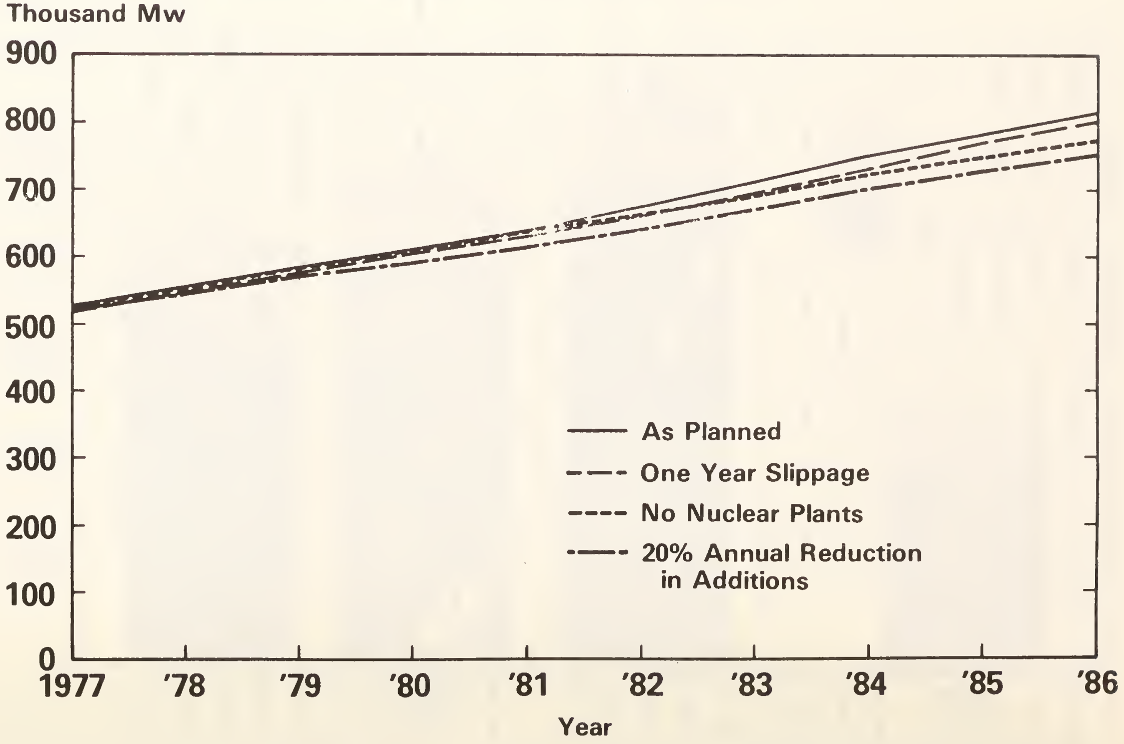


vary between 895 and 988 million Kwh, a difference of 10 percent. From the foregoing discussion, it is apparent that the potential for error, given a reliability criterion, is rather substantial in terms of demand estimates alone. The error, however, may well be in the direction of less growth, say around 5-5.5 percent per year, rather than more.

Construction Shortfalls. - Aside from the inability to accurately project future demand, there is uncertainty in regard to construction schedules for new plants. This is compounded by the long lead times associated with planning. For example, in some cases it can take as much as 14 years from conception to completion of a plant. This long lead time increases the probability of slippage because of the built in delays along the way, and the greater opportunity for problems and difficulties to crop-up. Approximately 20 percent of the incremental base load capacity planned for installation between 1977 and 1986 is not yet under construction, and thus is particularly vulnerable to delay.

Despite the strong possibility of delay the impact on capability does not appear substantial except in the most stringent case. Figure 4 shows 4 capability cases. Case I is the utility expectation based on current plans; case II assumes a one year delay in the year in which new capacity comes on line; case III assumes a moratorium on new-nuclear capacity after 1981; and case IV assumes a 20 percent reduction in annual capacity additions. The latter, in effect, assumes that no plant not now under construction will be completed by 1986. For our purpose, we have chosen to take 20 percent off of the annual additions. In reality, capacity would be higher than shown on the chart in the years 1977-82, and lower in the succeeding years through 1985; the 1986 figure would be the same in each instance. The 1977-82

Figure 4 - Summer Capability Under Various Assumptions, 1976-86

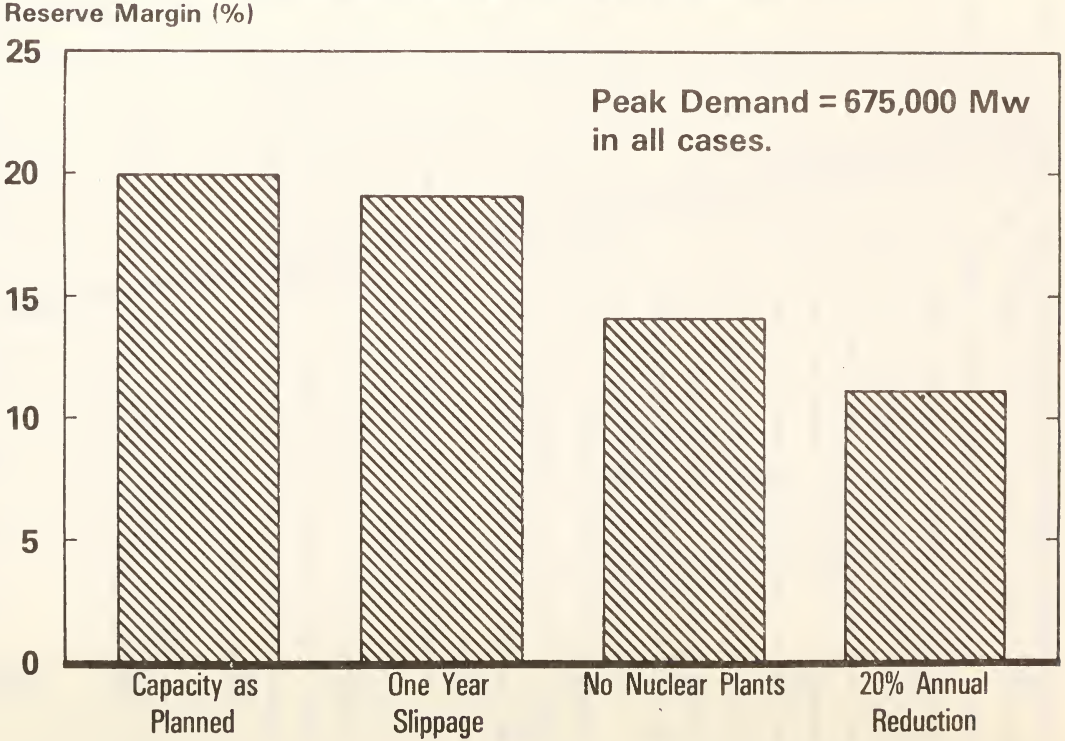


period encompasses the bulk of the plants currently under construction, while the 1983-85 period includes most of those planned but not yet started. In any case the figure indicates that a one year slippage is not very significant, and that even a 20 percent reduction only results in a 7.5 percent drop in capacity. This occurs because capacity in existence today comprises 65 percent of the 1986 case I projection; of this, approximately 1 percent will be retired, or derated, after giving effect to upratings. Therefore, only one-third of the 1986 capacity constitutes additions. As a result, a 20 percent cut-back in these has a relatively minor impact on total capability over the 10 year planning horizon. If the cut-backs were to continue long enough, however, the effect on electrical service could be dramatic.

Despite the relative insensitivity of capability data to construction cutbacks over the mid-term, the impact on reserve margins can be rather serious, assuming acceptance of the current reliability criteria. Figure 5 compares the capability data from Figure 4 against a constant peak. Our 7 1/2 percent drop in capability results in a drop in reserve margin from 20 percent to 11 percent. Anderson has noted that margins of 20 percent and over are a luxury, 15-19 percent are comfortable, 10-14 percent tolerable, 5-9 percent serious, and below 5 percent at the crisis level.[8/] Thus, the relatively modest decline in capability would result in a drop from luxury to barely tolerable. In this connection, note that the numbers have been selected to illustrate a point, and are not a forecast.

8/ Anderson, K. P., "Electric Utility Industry Loads and Resources in 1985: The Regional Picture," NERA.

Figure 5 - Reserve Margin Under Various Construction Assumptions, 1986



Equipment. A final category of uncertainty is the kind of equipment and its tendency not to operate. For example, it has generally been noted that smaller units are more reliable than newer and usually larger units, and that nuclear units are less available than coal units. These statements may be correct, but a recent article indicates that the smaller units are generally more mature, (i.e. have the bugs worked out) and thus are more reliable. The larger units may reach the same stability at the same relative age.[9/]

Insofar as coal versus nuclear is concerned, Lapides notes that a forced outage on a coal unit will occasion the rescheduling of maintenance to take advantage of the downtime. Nuclear plants, on the other hand, are prisoners of the refueling cycle. As a consequence, a forced outage is a forced outage and planned maintenance stays planned. In any case, the uncertainties engendered by equipment are relatively easy to keep track of and thus are accounted for in the reliability calculations.

Today and Tomorrow

The uncertainties discussed above have resulted in extensive debate concerning the adequacy of electrical energy supply in the U.S., and the ability of the utilities to maintain the current level of reliability.

In order to review the situation we have extracted data from various sources arranged by reliability council regions. These were established by the FPC as voluntary groups of electric utilities (public, private, and

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9/ Lapides, M., "Predicting Generating Unit Performance," EPRI Journal, April 1976, pp. 26-30.

cooperatives) for the coordination of planning, construction and operation of the bulk power supply system. The regions are as follows:

1. East Central Area Reliability Coordination Agreement (ECAR)
2. Electric Reliability Council of Texas (ERCOT)
3. Mid-Atlantic Area Council (MAAC)
4. Mid-America Interpool Network (MAIN)
5. Mid-Continent Area Reliability Coordination Agreement (MARCA)
6. Northeast Power Coordinating Council (NPCC)
7. Southeastern Electric Reliability Council (SERC)
8. Southwest Power Pool (SPP)
9. Western Systems Coordination Council (WSCC)

The areas served by each council are indicated in Figure 6.

The Current Situation

At this point in time there is little doubt that the U.S. has more generating capacity than it needs. Figure 7 indicates that reserve margins are above 20 percent in every area of the U.S., and in several cases are above one-third. Given the reliability criteria, an 18-20 percent reserve margin appears to be adequate for most systems. This overabundance comes about because of the lower than expected demand and the leads and lags in the supply system. That is, because it takes so long to get a plant on line, many of the units now producing entered the pipeline as long ago as 10 years. At that time, electrical consumption was still doubling every decade and utility plans were made on that basis. With the decline in demand in the 1970's, discussed in an earlier section, came a reduced need for capacity. Utility generating unit construction, however, unlike

Figure 6 - Regional Reliability Councils of the National Electric Reliability Council

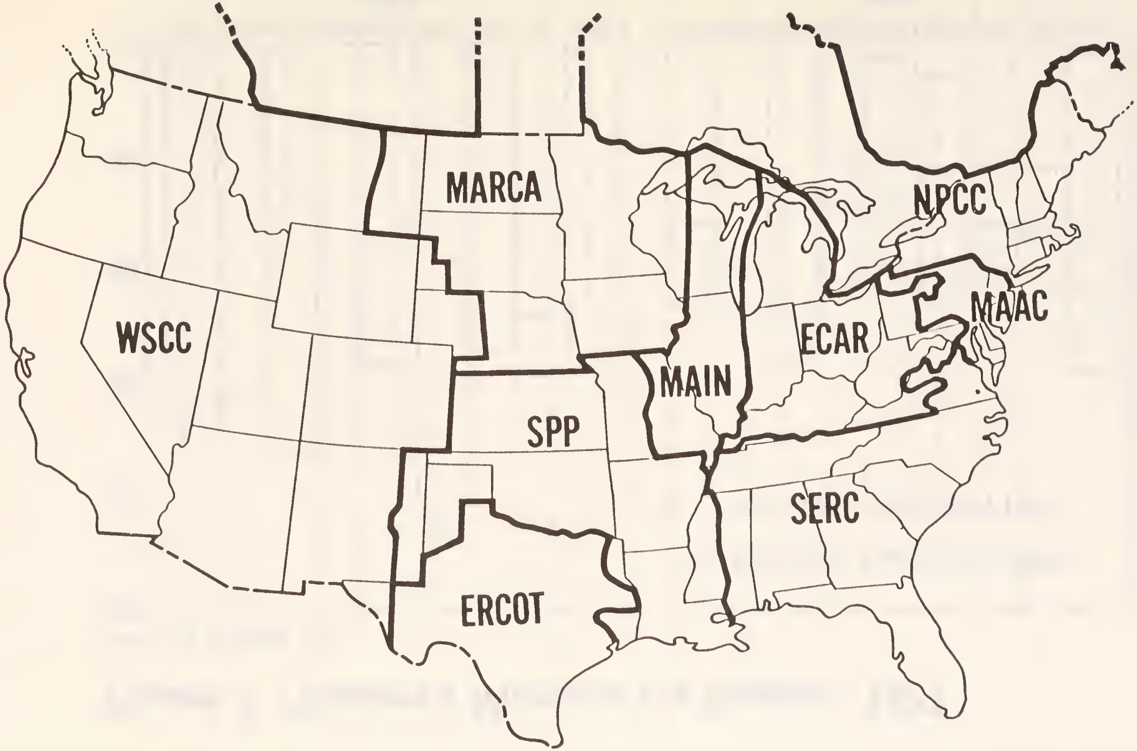
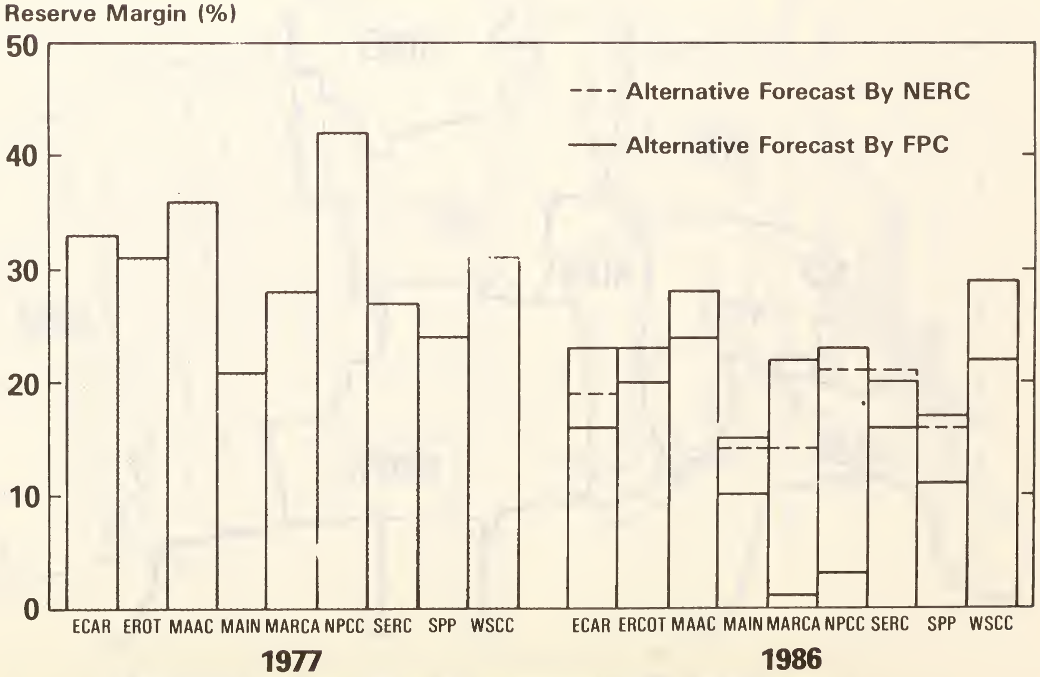


Figure 7 - Reserve Margins by Region, 1977



Source: EEI, 1977 Annual Electric Power Survey, April 1977, p. 6. & FPC Order 383-4, Docket R-362, May 16, 1977, p. 28.

the electricity it produces, cannot be turned off very easily. As a consequence, we now have more than we need.

The Future Situation

The outlook to 1986, however, is not quite as sanguine again accepting the current reliability criteria, and based on utility sources. While the Edison Electric Institute (EEI) projects an adequate margin for the U.S. as a whole, problems are forecasted for the Mid-America Interpool Network and the Southwest Power Pool (Figure 7- top solid line).

A much more pessimistic view is taken by the National Electrical Reliability Council (NERC) (Fig. 7. -dashed line). Their forecast, assuming a 5.7 percent annual growth rate for demand, indicates problems for MAIN, MARCA, and the SPP. The U.S. as a whole is projected to have a comfortable margin. NERC, however, does note that if demand grew by 6.2 percent annually rather than 5.7 percent, and if coal plants not under construction and nuclear plants under construction were delayed 1 year, while coal plants for which there is no corporate committment and nuclear plants without construction permits are delayed 2 years, then generating deficits could begin in SERC as early as 1979, and in all regions by 1986.[10/]

In any case, the FPC staff analyzed the reliability council data and indicated some doubt that the postulated reserve margins could be attained.[11/]

This observation was based on the financing difficulties, environmental pressures and procedural delays experienced by the electrical utilities in

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[10/] Referenced in footnote 6, p. 7.

[11/] Federal Power Commission, Bureau of Power Staff Report, Electric Power Supply and Demand 1977-1986, As Projected by the Regional Electric Reliability Councils in their April 1, 1977 Responses to FPC Order 383-4, May 16, 1977, p. 2.

recent years. The Commission staff pointed out that the reliability council reports project an addition to nuclear generating capacity of 131,000 megawatts (MW) over the 1977-86 period. For this same time period, the Nuclear Regulatory Commission (NRC) projects an increase in nuclear generating capacity of 90,000 MW. If the NRC projection proves to be correct, a substantial reduction in reserve capacity would occur and, according to the Commission Staff, result in inadequate reserve margins in several reliability regions, as shown in Figure 7 (lower solid line). The NRC estimate, added to existing capacity, is rather close to a recent CRS estimate. In a recent study, CRS postulated a reference case total of 131,000 Mw of nuclear capacity in 1985.[12/]

It should be noted that these reserve margins do not include the effect of projected net regional interchanges of power. If these are given weight in the computations, a somewhat different picture might emerge. It is also not obvious that the NRC projections are any more accurate than those of the reliability councils or that these NRC projections of nuclear generating capacity can simply be interjected into the reserve margin criteria presented by the councils. Further, there is an assumption that the utilities will do nothing to make-up the nuclear deficit. Presumably, the companies would switch to other types of plants or install short-lead time units such as combustion turbines. The latter would be an expensive alternative.

A final point to be made is that the appropriateness of currently accepted electric utility industry reliability standards -- which would be used to judge the adequacy of service in any projection of supply/demand conditions -- has

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[12/] CRS, "Project Interdependence: U.S. and World Energy Outlook Through 1990," Senate Committee on Energy and Natural Resources and Committee on Commerce, Science and Transportation, as well as the House Committee on Interstate and Foreign Commerce, Publication 95-31, June 1977, p. 36.

recently come under question. Recent advancements in transmission technology have resulted in an increased and increasing number of interconnected utility systems. These developments, coupled with the high and rising cost of new generating facilities and increased environmental concern, have caused some industry observers to contend that current reserve margins could be lowered while still maintaining the same level of system reliability; or even that the reliability standards, themselves, should be lowered. This latter point we will discuss at some length in a later section of this report.

It should also be noted that much depends on the rate at which demand for electricity grows, and particularly the growth of the peak. If the movement towards time-of-day pricing of electricity is successful in dampening peak growth, capacity requirements may be less and reserve margins larger assuming the current construction plan.

For example, one could contend that electric energy consumption will grow at no more than an average of 5% per year over the 1977-86 period. If we assume load factor at 61%, a distribution among regions equal to that forecast by the EEI, and a capability equal to that in our Case IV (20% annual reduction from "as planned"), we arrive at a forecast at variance with what can be considered conventional wisdom. Table 2 shows that under the above assumptions, no area of the country will be below 20% reserve margin in 1986, and six will be at 25% or more. It should be noted that with the postulated lower demand, and the assumption of virtually no new starts in plant construction beyond those already under way, there does not appear to be the possibility of an electrical shortage in the 1980's. It would appear that the utilities are reacting in a rational manner to the expectation of lower demand by consistently reducing their construction plans. If those plans are being cut-back because

Table 2 - A Possible Supply-Demand Scenario, 1986

Region	Capability 1/ (Million kw)	Peak Load 2/ (Million kw)	Reserve Margin %
ECAR	113.4	85.2	25
ERCOT	53.3	39.5	26
MAAC	58.6	41.7	29
MAIN	60.8	48.5	20
MARCA	34.5	25.9	25
NPCC	60.8	45.7	25
SERC	158.5	121.8	23
SPP	75.9	59.2	22
WSCC	135.2	96.5	29
Total U.S.	751.0	564.0	25%

1/ CRS Case IV, assumes a 20% per year reduction in capacity additions.

2/ Assumes a 5% per year average growth in energy, and a 61% load factor.

of an inability to borrow, then it indicates the financial markets perceive the market uncertainty that exists for the output of the new plants.

In any case, it appears that if demand growth is moderate, the U.S. will experience no shortages through 1986. If, on the other hand, demand growth follows a somewhat higher trajectory, there is a possiblity of regional difficulties. The seriousness of this problem is, to an extent, a function of the strength of regional interties, and how reliable we believe the system should be. The latter question we will take up in the next section.

Should the Lights Always Go On?

As noted earlier, the answer to the question posed by the chapter title would, under the engineering view, be yes. The economist, however, would take a somewhat different view of the reliability question. We will now discuss the latter in some detail.

The Economic View

Rather than take demand and the reliability criterion as given, the economic view would attempt to determine the reliability criterion at which benefits equal costs, and then to compute the reserve level needed to maintain that criterion. Thus, it is possible that, in economic terms, it may be best for the lights not to always go on. Put another way, to the economist the relevant view is not the optimal system reserve level needed to meet estimated demand, but rather the reliability criterion at which the incremental savings in social cost resulting from the installation and maintenance of reserve capacity will be maximized in relation to the cost of an incremental unit of capacity.

In regard to the costs and benefits, one must keep in mind that these are economically pertinent only at the time of receipt. Yesterday's costs or benefits are "water over the dam," and thus not economically relevant today. We are, therefore, looking into the future, but a dollar received today has a greater value than one due 10 years later. As a consequence, the time flow and pattern of costs and benefits will play a role in estimating the efficacy of a specific reliability criterion. This can be rather crucial in the sense that costs for equipment will be incurred early in the cycle, but benefits from reliable service will not accrue until later.

The time span over which the costs and benefits are measured is also important because short-run social costs will tend to be greater from a lack of reliability viewpoint than those incurred over the long-run. This will occur because industry, business, and individuals will adjust to the continuing contingencies. For example, a business requiring a high level of reliability will install its own emergency capacity, or may contract for more reliable service at a premium rate. On the other hand, those not requiring such a high level of reliability might simply close down during interruptions.

From the foregoing, it is apparent that to the economist the basic question is what will a given level of reliability cost and what do I get for the expenditure?

The Cost of An Outage

The cost of a given level of reliability is relatively easy to compute, given the future make-up of the system. The benefits accruing from these expenditures are difficult to determine, and are dependent on the cost of an outage.

The only available "hard" data, is that collected by Ontario Hydro.[13/] These reports indicate that costs per Kw of peak load increase dramatically for most users as the outage duration increases (Figure 8). There was also a rather wide range of values for each outage interval. This resulted from

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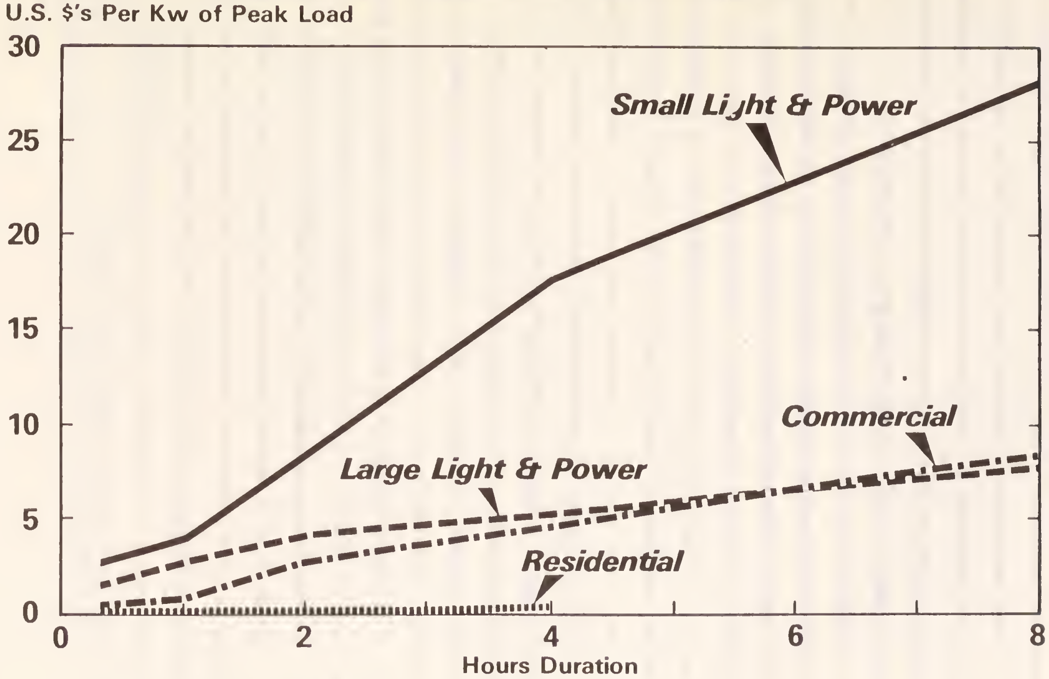
[13/] Ontario Hydro Survey On Power System Reliability
A. Viewpoint of Government and Institutional Users, R & U 78-1.
B. Viewpoint of Small Industrial Users, R & U 78-3.
C. Electric Power Supply Reliability Survey II (by Market Facts of Canada Ltd).

Figure 8 - Cost of An Outage, by Duration, & Customer Class, Ontario Hydro



Source: Berk, L.H., "Update On Ontario Hydro Surveys on Supply Reliability: Viewpoint of Selected Customers Groups" Canadian Electric Assoc., 3/15/78.

the diversity of industries surveyed and the relative importance of electricity to each. The industrial customers also indicated that a 5 percent voltage reduction was tolerable, but 10 percent would result in production curtailment. Most of these also stated a preference for longer but less frequent interruptions rather than frequent but short outages totaling the same duration.

The industrial customers have been broken into 2 groups: (1) large light and power--those having a demand of 5000 kw or over; (2) small light and power--those having a demand below 5000 kw. The latter group estimated an outage cost substantially above that of the other groups.

Commercial customers indicated a relatively modest cost for outages of short duration, but rather substantial costs for longer outages. In fact, the cost of an outage under one hour in duration appear relatively inconsequential.

Residential customers, on the other hand, preferred more frequent but shorter outages. In general, a 20 minute per day power interruption did not appear onerous to most such consumers in that fully half were unwilling to pay a premium for assured service. A quarter of the consumers were willing to pay as much as a 10 percent premium for such service, but very few were willing to pay more. If the outage reached 4 hours per day, sentiment changed rapidly: 80 percent were willing to pay a premium of at least 5 percent for assured service; 50 percent were willing to pay at least a 10 percent premium; and 25 percent would pay 20 to 50 percent more.

Insofar as interruption costs for institutions are concerned, the non-dollar costs far outweighed the dollar costs. The former include possible riots, prison escapes, stolen property, delays, etc. Whether the Canadian data can be applied to the U.S. customer is an unknown.

Aside from the above, an effort was made to evaluate the cost of the Consolidated Edison blackout of July 13-14, 1977.[14/] This study placed the outage cost at $310 m for the 25 hour blackout. Of this, approximately 44% comprised riot damage, emergency governmental services, repair and replacement of government buildings and equipment, cleanup, the arrest and processing of rioters, and compensation and treatment costs for injured police and firemen. The remaining $173 m in losses were classified as economic losses. These comprised an allowance for output lost and deferred, Con Ed costs, spoilage and damage, and lost governmental revenues. Available data indicate an energy loss of 140,000,000 Kwh as a consequence of the blackout. Thus, the cost per Kwh of the outage would be $2.21. Of this, $1.23 was an economic cost, and $0.98 was social cost.

A somewhat different approach was taken in a recent EPRI Workshop. [15/] A paper by Behling (p. 4-14) in the proceedings volume indicated that an 8% drop in electricity production as a result of a 40% drop in expected 1985 nuclear capacity would cause a 3.8% decline in GNP. A 22.3% decline in electricity production would result in a 16.8% drop in GNP. A somewhat similar study by Shew (pages 4-70 to 4-77) indicates a 5% capacity shortage would result in an $820 m GNP loss, while a 20% shortage would result in a $23,256 m loss. Various other computations were made by Shew in which gross reserve margins were varied from 15 to 20%, and the outage costs were assumed at $0.61, $1.04, and $1.20 per interrupted Kwh. GNP losses, depending on assumptions, varied between $147m at a 5% capacity shortage to a high of $14,418 m for a 20% capacity shortage.

[14/] Referenced in footnote 1; pages 5-12.

[15/] Sigma Research, Inc. "Workshop Proceedings: Environmental and Social Impacts of an Electricity Shortage", EPRI, June 1978, EA-796-SR, WS-77-24.

There have been several other efforts to evaluate the cost of an outage as shown in Figure 9. Theses estimates range from a low of 50 cents to a high of $1.20 per Kwh. The wide cost range results from the different time frames, methods, and assumptions used in each study. The Heising estimate was in a comment to the Shipley paper and relates to the Swedish experience.[16] The FPC estimate is derived from a supplementary study attached to an FPC report on the adequacy of future electric power supplies.[17] That study indicated a 12% reduction in electric supply might reduce GNP by 7% in the short run, implying an average cost of 50 cents per Kwh for an outage.

The Costs and Benefits of Reliability

The Shipley, Telson, and Kaufman studies attempt to relate the outage costs to the cost of reliability levels. As a consequence, we will review them in somewhat more detail below.

Shipley, et all.[18] The authors see two basic approaches to the cost of power interruptions: one is from the viewpoint of the power consumer, with this varying by type of consumer; the second approach is from the perspective of the electric utility. The latter costs include loss of revenue from load not served, loss of future potential sales, and loss of community good will with possible associated adverse action. The

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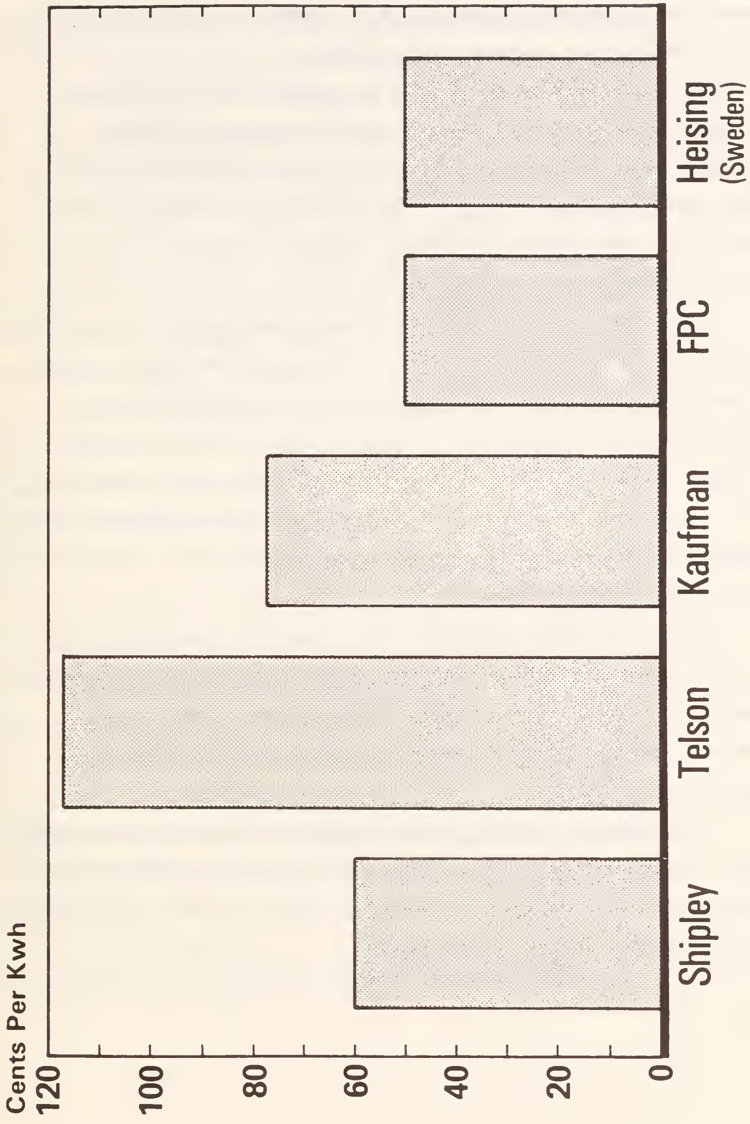
[16] Heising, C.R., IEEE Transactions, July - Dec. 1972, p. 2208.

[17] Technical Advisory Committee on the Impact of Inadequate Electric Power Supply, "The Adequacy of Future Electric Power Supply: Problems and Policies," FPC, p. 75.

[18] Shipley, R. B., A. D. Patton and J.S. Denison, "Power Reliability vs. Worth," IEEE Transactions on Power Apparatus and Systems, July - December 1972, pp. 2204-7.

Figure 9 - Cost of An Outage Per Kwh Lost



authors opt to approach the problem from the consumer viewpoint because they believe it to be more readily quantifiable.

The Shipley methodology takes GNP as a measure of the total output of goods and services and of society's comfort, convenience and safety. They then assume that GNP will be reduced in direct proportion to the Kwh interrupted. An average value for a Kwh is obtained by dividing the GNP for a year by the electricity consumed. Using then current data yielded a value of about $0.60 per Kwh for interruptions as a nationwide average.

The reliability of the electrical system is measured by service availability. The authors define service availability as the ratio of Kwh actually supplied to Kwh which would be supplied if there were no service interruptions. Service availability thus ranges from zero to unity, with unity equaling no interruptions. It is expected that the total electric power related cost to the nation would be minimized for that value of service availability which minimizes the sum of utility system owning and operating costs, plus the total annual cost of power interruptions.

This study, as do the others, concludes that electrical systems studied (1967 data) are more reliable than can be justified on the basis of economics. The authors do note, however, that a reliability level somewhat higher than that indicated by pure economics can be justified on the basis of unquantifiable factors.

The mathematical analysis presented indicates that optimum service availability is achieved when the incremental costs of providing availability in all parts of the system are equal, and when these costs are equal to the incremental cost to consumers of service unavailability.

Telson.[19/] - Telson begins by examining the cost of providing an incremental quantity of production through installation of an additional quantity of generation to a system built to a reliability criterion of one day in ten years. His calculations indicated that society would be paying over 200 times the net revenue value of additional energy produced by the "incremental" megawatt. The question of reliability then is whether or not having this rarely used energy available is worth the cost. Society is paying for something it rarely uses. In other words to have this capacity on line for those rare instances when customers "demand" its use means that energy that normally would cost 4 cents will cost $8.00

He also prepared calculations attempting to measure the losses caused by not having energy available. As a consequence, Telson felt that a one day in 10 year loss of load probability, which is a common reliability criteria level in the United States, is probably too conservative. He felt system reliability levels could be reduced to perhaps a 5 day in 10 year criterion. The quality of service as perceived by most consumers would not be impacted because the distribution network operates at a lower level of reliability compared with generating equipment.

In supporting his conclusion, Telson notes that loss of load incidents as reported under FPC Order 331-1 were generally the result of transmission or distribution system failures rather than as a consequence of inadequate generating capacity. Telson thus argues that generation reliability could be reduced to match the lower distribution system reliability with minimal impact on the consumer.

[19/] Telson, M. L., "The Economics of Alternative Levels of Reliability for Electric Power Generation Systems," The Bell Journal of Economics, Autumn 1975, Vol. 6, No. 2, pp. 679-694.

The Telson study utilizes the PROSIM (probabilistic simulation) method which recognizes that generating units are not perfectly reliable and incorporates this assumption into its calculations. PROSIM was developed in Belgium by Baleriaus and Jamoulle.

Telson does note there is a value to the relatively high reliability level common in this country due to uncertainties regarding demand and construction, but this value is extremely difficult to quantify.

Kaufman.[20/] - This study is based on the New York State system. Computations prepared by the New York Power Pool indicate reserves could vary from a low of 14.5 percent to maintain a one day in one year criterion, up to 20 percent for one day in ten years. The author noted that these computations are sensitive to interconnections.

Kaufman finds some power pools do not consider their interconnections to the degree they might, resulting in what he feels is an unrealistically low reliability index.

He computed costs and benefits under various assumptions (Figure 10). Costs were based on the use of combustion turbines for peaking energy. Benefits were computed as the value of outages that do not occur because the generating reserve exists. The outages that do not occur were valued at the losses to society resulting from curtailment of goods and services because of the outage. This was based on Value Added data. Determination of the optimum reliability criterion was based on calculation of the internal rate of return.[21/] As will be noted on Figure 10, the benefit levels tend

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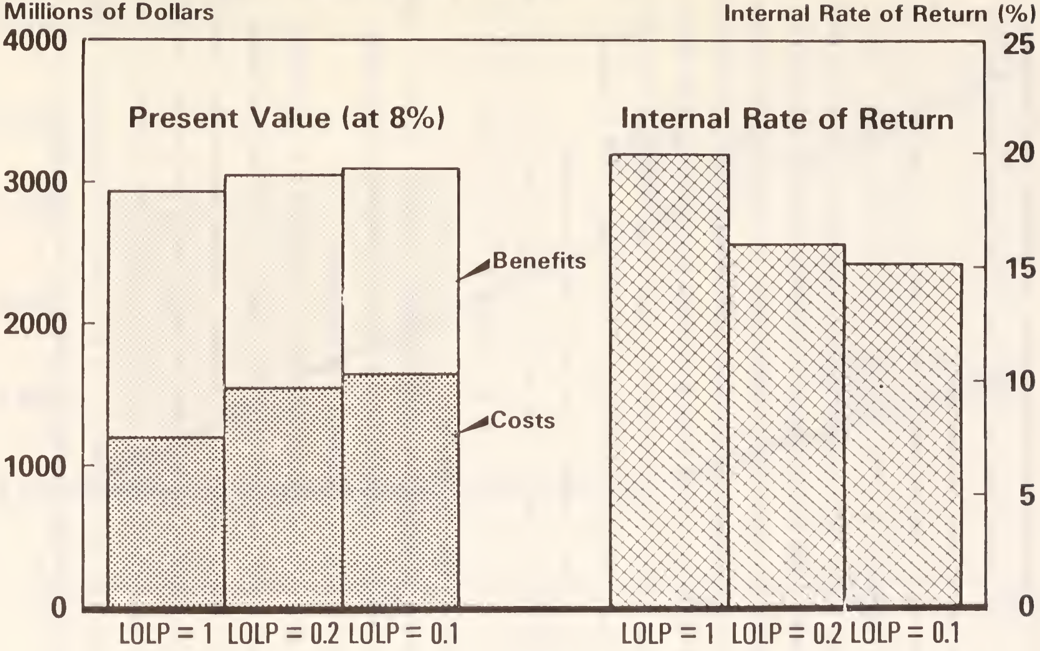
20/ Kaufman, A., "Reliability Criteria - A Cost Benefit Analysis," N.Y. State Department of Public Service, O.R. Report 75-9, August 1975.

21/ The internal rate of return is that rate of discount that would make the present value of benefits less costs equal to zero.

Figure 10 - The Relative Value of Costs & Benefits By Reliability Criteria



Source: Kaufman, A., "Reliability Criteria - A Cost Benefit Analysis" New York P.S.C., August 1975, p. 19 - 20.

to be rather close together, but costs vary. As a result, the internal rate of return for the lowest level of reliability is the highest indicating this this may be the optimal criterion level.

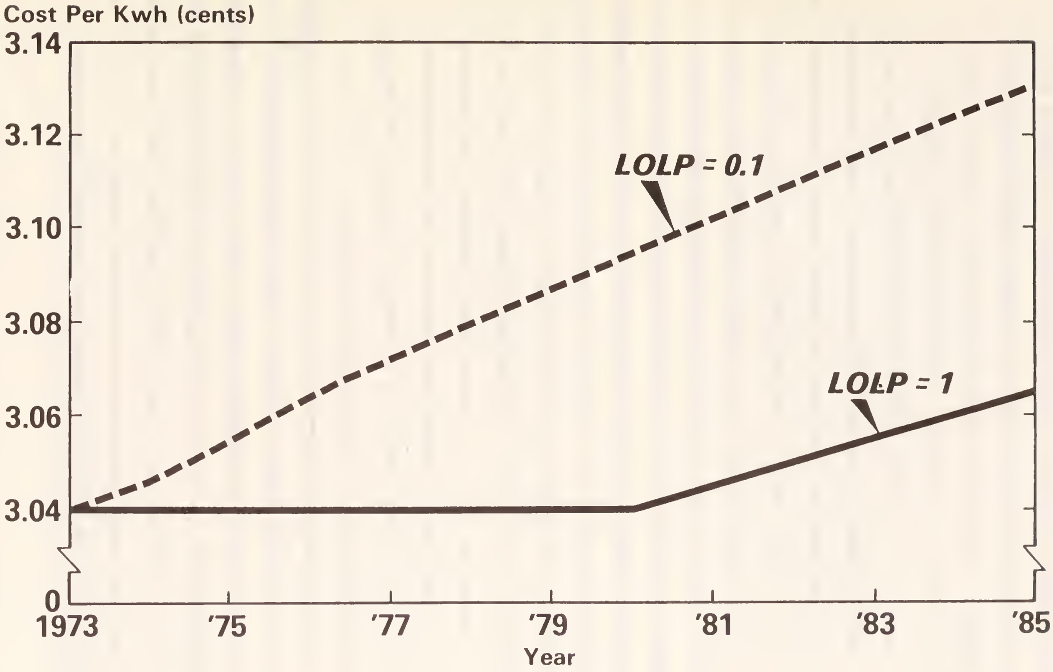
These computations indicated a capital saving of $20 million (m) in the first year as a consequence of a shift to a one day in one year criterion. This saving would peak at $36 m seven years later, and decline to $12 m five years after the peak. This saving, together with reduced interest, taxes and rate of return requirements, would impact consumer rates. At the one day in ten year level, the cost per kwh (figure 11) would rise 3 percent over the 12 year period; at the one in one level there would be less than a 1 percent increase. The flat curve in the 1973-80 period for LOLP = 1, results from the ability to use existing capacity without new construction until the lower reserve level is reached. In short, the system is overbuilt in terms of the new criteria.

The report indicates that the one day in one year level would be 0.2 percent less costly in the first year than the one day in ten year level; by 1965 the difference would reach 2.2 percent.

According to Kaufman this relatively small (2 percent) reduction in rates by 1985 for the lower reliability level may not be worthwhile, particularly when balanced against a probable rise in complaints.

The author also notes that generating, transmission and distribution systems should have comparable reliability levels in order for total system reliability to be of benefit to the consumer. Kaufman suggests that information is also required on the number of outages, their duration and severity, that might occur at each reliability level, as well as the characteristics of the customers who might be impacted. He feels the latter is particularly important in computing the societal benefits for each level of reliability.

Figure 11 - Cost Per Kwh at Various Reliability Levels



Source: Kaufman, A. "Reliability Criteria - A Cost Benefit Analysis" N.Y.P.S.C., p 24.

Kaufman suggests that until these further studies are prepared and evaluated, the present one day in ten year criterion should be maintained.

A Critique. - The three studies discussed above, all make an effort to evaluate the costs and benefits of specific reliability levels from a societal viewpoint. All conclude that less reliability would be appropriate. There are, however, several problems with these studies. Losses are usually assumed to be proportional to the energy not served, regardless of the size and timing of an outage, because of the complexity of computing costs and benefits. Smaller outages, however, may impose a smaller cost per kilowatt hour lost than larger outages. These studies also largely ignore capital and non-monetary losses, so that the losses reported are restricted to the loss of income or output. Further, the distribution of outages across customer types is not treated explicitly. The cost per kilowatt hour lost is taken to be an average for all customer groups, with energy losses assumed to be proportional to consumption. Lastly, the indirect effects are typically not counted. An outage has a kind of reverse multiplier effect. For example, if a producer of bolts falls behind in his production as a consequence of a blackout, the producer of cabinets in a different area may not be able to assemble those cabinets as a result of the bolt shortage.

Aside from these difficulties, a recent report noted that none of the studies had evaluated the use of reserve margin as a buffer against uncertainty.[22/] As a consequence, the margins may be overstated in an effort to protect reliability in a changing world, as well as to protect against forced outages and other contingencies. If the reliability criterion is to be propertly evaluated, a method of considering this in the evaluation needs to be developed.

[22/] Federal Energy Administration, "Electric Utility Rate Design Proposals, Interim Report," February 1977, FEA/D-77/063, pp. 181-195.

APPENDIX

LOLP and Rate-Making

The use of LOLP is becoming more widespread in utility reliability studies. In addition, it has recently been suggested that LOLP be used in rate making, particularly in the distribution of marginal costs. This springs from the considerable interest over the past several years in electric utility rate reform. As the price of electricity has risen at a fairly rapid rate, after several decades of stable or even declining prices, interest has developed in restructuring electric utility rates so that they more accurately reflect the costs of providing electrical service. The inter-related issue of energy conservation has also caused increased interest in utility rate reform, as more efficient pricing mechanisms are also seen as a stimulus to efficient end-use of electrical energy.

Historically, electrical energy has been priced at average cost. Electricity, however, is basically a nonstorable product and demand varies over the hours of the day and seasons of the year. The cost of providing electrical service varies with the level of demand placed on the utility system, and thus also varies with time. Time-of-day rates, which can be based on average or marginal costs, charge varying rates for electrical service depending on the time of consumption. This type of pricing mechanism is designed to more accurately reflect the costs of providing service to the utility's customers. Time-of-day rates have been developed in several jurisdictions [23/] and have been implemented on both an experimental and mandatory basis.

[23/] The commissions in Connecticut, New York, Virginia and Wisconsin require electric utilities to measure the cost of providing service to each customer class by time-of-day and season of the year.

The National Economic Research Associates (NERA), an economic consulting company, has become a leading advocate of time-of-day (TOD) marginal cost based utility rates. Through testimony presented in various utility rate structure proceedings, and through participation in the EEI-EPRI Electric Utility Rate Design Study, NERA has developed a method of calculating electric utility TOD marginal cost based rates.

One of the major procedures employed by NERA to develop marginal cost based electric utility rates is the use of loss of load probability (LOLP) to assign marginal capacity costs to the various pricing periods. The following discussion describes the NERA methodology used in developing TOD marginal cost based electric utility tariffs. Criticisms of the NERA methodology and its effect on electric utility prices are also discussed.

The NERA Method

In developing its marginal cost TOD rates, NERA separates the costs of providing electric service into three components: customer-related, demand-related and energy-related cost.[24/] Marginal customer-related costs are those costs associated with "building and having in place an electric system that provides area coverage and 'hook-up' for a population of minimum demand customers."[25/] These annualized costs are the administrative, capital and operating costs associated with

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24/ The discussion on NERA's method of calculating marginal cost rates is based on testimony presented by NERA before the Colorado Public Utilities Commission, in Case No. 5693, August 5, 1977; and in How to Quantify Marginal Costs: Topic 4, a report prepared for the Electric Utility Rate Design Study, March 10, 1977.

25/ An Analysis of the Time-Differentiated Marginal Costs of the Public Service Company of Colorado, Case No. 5693, by National Economic Research Associates, Inc., August 5, 1977, p. 5.

providing service to a utility's customers, and vary with the number of customers on the system. Thus, they are charged on a non-time differentiated basis.

Marginal demand-related costs are the costs associated with building and maintaining an electrical system with sufficient capacity to meet incremental electrical demands. This is best determined, according to NERA, by analyzing the company's load duration curve and determining what increases in costs would result from an increment in demand at any time. Because of the discontinuous nature of plant adjustments (i.e. plant additions are made in large increments in order to realize economies of scale and are used to serve the present demand on the system as well as anticipated future demand), and because of the uncertain nature of the actual demand placed on the system at any point in time, NERA analyzes the load duration curves of the company for a 5 to 10 year period in order to derive the long-run marginal cost of capacity for the system. The marginal cost of capacity will be the cost of the plant used to meet the load having the shortest duration, i.e. the plant used to serve the peak demand. For most systems, NERA states, this will be the cost of a peaking unit, although for some systems with a relatively broad peak period, an intermediate or cycling unit would be used to meet a peak of relatively long duration. The cost of this plant, then, should be used as the marginal cost of capacity. The marginal demand-related cost also includes the cost of the demand-related portions of the system's transmission and distribution facilities.

Marginal energy costs are the costs of producing the energy delivered on the system and include the fuel and variable operating and maintenance expenses associated with increments of demand. Again, because utility systems oscillate around an optimum generating mix (because of the uncertain nature of demand and incremental additions to capacity), NERA states that it is desirable to analyze marginal energy costs over a 5 to 10 year period.

The marginal energy cost of the system during any hour of operation is simply the fuel and variable operating and maintenance expense of the last machine on line. This is generally the machine with the highest running cost. Thus it is possible to derive the marginal cost for the system for each hour over a 5 to 10 year period.

In summary, we now have a marginal customer-related cost which varies with the number of customers on the system; a demand- or capacity-related marginal cost which is the cost of the unit used to meet peak demand (usually a peaking plant); and an energy-related marginal cost which is the fuel and variable operating and maintenance expense of the last unit on the system during any hour of operation. The customer-related marginal cost is a per customer charge for each month of the billing period; the demand-related marginal cost is per kilowatt (Kw) of peak demand; and the energy-related marginal cost is per kilowatt hour (kwh) of energy usage. These costs must now be assigned to the hours of the day and season of the year according to the demands placed on the system.

Developing Cost Periods.- NERA states that marginal cost - both marginal capacity and marginal energy costs - vary over the utility's load cycle, and that these costs tend to vary directly with the probability that demand on the system will exceed available capacity. Therefore, the loss of load probability (LOLP) becomes a primary criterion for developing costing and pricing periods.

In regard to marginal capacity costs, NERA remarks that these costs cannot simply be charged to the hour of maximum demand on the system, but rather must be assigned to each hour based on the probability that load will exceed supply in that hour. This is so because although the system is built to serve the peak demand, the planners of the system construct a mix of generating facilities - base load, intermediate, and peaking units - which are designed to supply electrical energy to meet the demands placed upon the system during each hour of the load cycle at the lowest overall cost. The customers on the system, then, should share the responsibility for the costs of providing the electricity demanded at any point in time in proportion to the probability that load will exceed available supply at the time of consumption.

Similarly, marginal energy costs vary with the time of consumption. For each hour of the year, the facilities available to the system are arranged in ascending order of running cost. Thus, the system marginal cost for each hour of operation is the running cost of the last machine on line at that hour, plus a share of the marginal capacity costs determined by the relative probability that load will exceed capacity during that hour.

In establishing cost periods for the purpose of allocating marginal capacity and marginal energy-related costs, the ideal would be to apply the absolute probability that demand would exceed available capacity in each hour of the year. This probability would take into account scheduled maintenance, equipment deratings, the probability of forced outages and the probability of error in the forecasted load. It would also be necessary to consider arrangements such as membership in a power pool or system interconnections with other utilities. An hourly pricing system, however, would be too detailed for customers to understand, and too costly and cumbersome to apply. Further, the marginal costs of supplying electrical service do not fluctuate to the extent that would make individual hourly charges necessary. Therefore, NERA recommends that hours of relatively similar costs be grouped together in a sensible fashion, and that marginal costs be computed for these periods.

The cost periods chosen by NERA are an attempt to work out a compromise between economic efficiency (by having prices vary with time of consumption) and customer acceptance and understanding.

By inspecting the company's daily load curves, NERA determines the diurnal peak and off-peak cost periods. These periods are selected by analyzing the average daily load curves for the peak (winter) and off-peak (summer) periods. For instance, in the current example, by selecting the period when average daily load is 80 percent or more of peak demand during the winter months, the hours of 6:00 a.m. through 11:00 p.m. are highlighted as potential peak-pricing hours. By analyzing the types of load on the system during these hours and considering the probable elasticities of customer demand, however, NERA selects the hours of 6:00 a.m. through 9:00 p.m. on week days as the peak-demand costing period for the winter season. The remaining hours of the weekdays and all hours on weekends are off-peak periods.

In a similar manner, peak and off-peak periods are selected for the summer (or base load) period. If load patterns had exhibited less of a sharp break between peak and off-peak usage, a third or intermediate, pricing period could also have been selected.

The marginal demand-related costs are allocated, based on LOLP, to the peak and off-peak periods. Marginal energy costs are then computed by a model of the utlity system. To these are added marginal customer costs to arrive at total marginal cost.

Some Comments.- The NERA method of computing marginal costs upon which to base time-of-day electric utility tariffs is essentially one of calculating the marginal capacity-related and energy-related costs and then allocating these costs to selected costing/pricing periods. As such, the NERA methodology has been the subject of some criticism by other analysts involved in electric utility rate structure reform.

Mr. W.A. Russell, a consultant appearing on behalf of the Colo. P.U.C. staff, criticizes NERA's method of allocating marginal costs to cost periods.[26/] Mr. Russell's discussion of the NERA method centers around various operational procedures employed by electric utilities in supplying capacity (both generation and transmission) to meet incremental demands on the system, and on the assumption made by NERA that marginal capacity costs vary in direct proportion to LOLP. While the operating procedures outlined by Russell certainly complicate the NERA procedure, they do no harm to its basic premises. Moreover, although often handled in a vague manner, the operational complications mentioned by Russell (including forced outage rate, load duration curve, system interconnections, and mix of generating facilities) are considered by NERA in its computation of marginal cost based rates. The issue here seems

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[26/] Case No. 5693, Before the Public Utilities Commission of the State of Colorado, Prepared Dirct Testimony of Winfield A. Russell on Behalf of the Commission Staff.

to be one of confusion between short-run cost fluctuations and long-run marginal costs. The NERA method appears to properly employ long-run marginal cost indices in computing time of day (TOD).

The fault Mr. Russell finds with NERA's use of LOLP to allocate marginal capacity costs to cost periods is potentially much more damaging to NERA than are his other criticisms. Russell points out that there is not a single method of computing LOLP, but that several methods are used with varying input data. Also, several utilities have discovered, according to Mr. Russell, that LOLP did not adequately measure reliability on their systems during last winter's adverse weather conditions. The question then is: does LOLP adequately take into consideration all of the factors involved in determining system reliability, and if so, is the calculation of LOLP consistent among utility companies? Neither NERA nor Mr. Russell adequately answer these questions. As indicated in an earlier section, however, it appears that LOLP is a very incomplete measure of reliability.

NERA's use of LOLP has provoked criticism from other participants in electric utility rate reform. A report presented by Task Force 4, a group of industry representatives and regulators involved in the ERI-EPRI Electric Rate Design Study for the National Association of Regulatory Utility Commissioners, raised some important issues in regard to the use of LOLP to assign marginal capacity costs to seasonal pricing periods.27/ The report points out the sensitivity of LOLP to small changes in load carrying capacity. The example presented in the report showed that a 4.8 percent change in load carrying capability resulted in a five fold increase in LOLP.

27/ See: Critical Issues in Costing Approaches for Time-Differentiated Rates, Prepared by Task Force 4 for the Electric Utility Rate Design Study, January 12, 1978.

This extreme volatility in LOLP could result in widely fluctuating utility rates since costs are assigned to pricing periods based on LOLP. This volatility appears to be dampened by the NERA procedure of using 5 to 10 year average values for LOLP, and grouping periods with similar load characteristics into seasonal cost periods.

The Task force 4 report was also concerned with NERA's lack of awareness "of the real world with respect to the generation capabilities, limitations and operation, which goes way beyond blindly using the LOLP values for assignment of costs." [28/] This concern for realism in marginal cost based TOD rates is shared by Dr. Ralph Turvey, an internationally known economist and analyst of electric utility marginal cost pricing. [29/] Dr. Turvey mentions the fact that peak demand periods on generation, transmission and distribution facilities often occur at different times, so that NERA's method of allocating the demand-related portion of these marginal costs to cost periods based on the same LOLP is an oversimplification of actual system operation. NERA mentions the possibility of different peak periods for generation and transmission facilities in its own discussion on marginal pricing, but seems to overlook this possibility when allocating marginal costs.

While Dr. Turvey has no objection to the basic approach taken by NERA in determining marginal cost based electric utility tariffs, his major

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[28/] Task force 4, op. cit., p. 52

[29/] See: Comments on National Economic Research Associates' Approach to Marginal Cost Pricing, Prepared by Ralph Turvey, Prepared for Electric Utility Rate Design Study, September 15, 1977.

difficulty with the NERA methodology is similar to that expressed by Task Force 4, and in a more indirect way by Mr. Russell. Dr. Turvey feels that NERA oversimplifies reality by placing too much emphasis on allocating marginal costs to cost periods rather than analyzing actual operational data and planning criteria to determine more realistic differentiations in marginal costs. Dr. Turvey notes that "the cost analyst must find out how the utility would react to a change in demand expectations; his job is not to work out how he thinks it ought to react."[29]

If marginal cost pricing is to serve its function of providing proper price signals to customers upon which to base their long-term electrical energy consumption patterns, it must accurately reflect the costs of providing service during the various times-of-day and seasons of the year. The use of LOLP to assign marginal costs upon which to base TOD rates appears to suffer from some difficulty in reflecting actual operational cost variations as experienced on the nation's electric utility systems.

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[29] Ibid.

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